The Cost of No Reform

Heffron, Raphael; Körner, Marc Fabian; Sumarno, Theresia ; Weibelzahl, Martin; Fridgen, Gilbert

Publication date:
2021

ADBInstitute

ADBI Working Paper Series

HOW DIFFERENT ELECTRICITY PRICING SYSTEMS AFFECT THE ENERGY TRILEMMA: ASSESSING INDONESIA'S ELECTRICITY MARKET TRANSITION

Raphael J. Heffron, Marc-Fabian Körner,
Theresia Sumarno, Jonathan Wagner,
Martin Weibelzahl, and Gilbert Fridgen

No. 1213
January 2021

Asian Development Bank Institute

Raphael J. Heffron is a professor for Global Energy Law & Sustainability at the Centre for Energy, Petroleum and Mineral Law and Policy at the University of Dundee, Scotland, UK and a Jean Monet Professor in the Just Transition to a Low-Carbon Economy awarded by the European Commission. Marc-Fabian Körner and Jonathan Wagner are doctoral candidates and research assistants at the FIM Research Center at the University of Bayreuth, Germany, and at the Project Group Business & Information Systems Engineering of the Fraunhofer FIT, Germany. Theresia Sumarno is an energy policy consultant at the International Institute for Sustainable Development (IISD) in Geneva, Switzerland. Martin Weibelzahl is a postdoctoral researcher at the FIM Research Center at the University of Bayreuth, Germany, and at the Project Group Business & Information Systems Engineering of the Fraunhofer FIT, Germany. Gilbert Fridgen is PayPal-FNR PEARL chair in Digital Financial Services at the SnT, the Interdisciplinary Centre for Security, Reliability and Trust at the University of Luxembourg, Luxembourg.

Suggested citation:

Heffron, R. J., M.-F, Körner, T. Sumarno, J. Wagner, M. Weibelzahl, and G. Fridgen. 2021. How Different Electricity Pricing Systems Affect the Energy Trilemma: Assessing Indonesia's Electricity Market Transition. ADBI Working Paper 1213. Tokyo: Asian Development Bank Institute. Available: https://www.adb.org/publications/how-different-electricity-pricing-systems-affect-energy-trilemma-indonesia

Please contact the authors for information about this paper.

Email: jonathan.wagner@fit.fraunhofer.de

The authors gratefully acknowledge the financial support of the Kopernikus-Project "SynErgie" of the Federal Ministry of Education and Research of Germany (BMBF) and the project supervision of the project management organization Projektträger Jülich (PtJ).

We gratefully acknowledge the Luxembourg National Research Fund (FNR) and PayPal for their support of the PEARL project "P17/IS/13342933/PayPal-FNR/Chair in DFS/Gilbert Fridgen" that made this paper possible.

Furthermore, we would like to thank Christoph Neumann and Maximilian Rinck for their valuable comments.

Asian Development Bank Institute
Kasumigaseki Building, 8th Floor
3-2-5 Kasumigaseki, Chiyoda-ku
Tokyo 100-6008, Japan

Tel: +81-3-3593-5500
Fax: +81-3-3593-5571
URL: www.adbi.org
E-mail: info@adbi.org

Abstract

Many countries have a clear policy objective of increasing their share of renewable energy sources (RESs). However, a major impediment to higher RES penetration often lies in the historically grown structures of a country's electricity sector. In Indonesia, policymakers have relied on cheap fossil fuels and state control to provide the population with access to both reliable and affordable electricity. However, this focus on only two of the three horns of the energy trilemma, namely energy security and energy equity (and not sustainability), may put Indonesia at risk of missing its ambitious RES targets. In this context, a number of small-scale reform attempts to promote RES integration in recent years have proved to be relatively unsuccessful. Like many other countries, Indonesia needs clear policy directions to avoid an unsustainable lock-in into a fossil fuel future. In the last decades, several other countries have successfully restructured their electricity sectors, for example by introducing a wholesale market for electricity under different electricity pricing systems, including nodal, zonal, or uniform pricing. These countries may hold valuable experiences of overcoming the historically grown barriers to successful RES integration through a greater role for market mechanisms. This paper develops three generic models that allow policymakers to analyze the impact of introducing either a nodal, a zonal, or a uniform pricing system on the three horns of the energy trilemma in their country. We evaluate our model using a simplified network representation of the Indonesian electricity sector. Our results indicate that each of the pricing systems is able to foster specific horns of the energy trilemma. Considering that any major reform intended to improve energy sustainability in Indonesia will only be a success if it also addresses energy security and energy equity, we also discuss our results from the perspective of energy justice and the need to balance the country's energy trilemma. Ultimately, we illustrate a transformation pathway for a more sustainable and just transition to a low-carbon economy in Indonesia.

Keywords: electricity pricing system, electricity market liberalization, energy trilemma, energy justice, Indonesia, renewable energy sources

JEL Classification: Q400, Q410, Q420, Q480, L510, L110

Contents

1. INTRODUCTION

Many countries around the world are implementing measures to increase the share of renewable energy sources (RESs). Historically, the focus of policymakers was primarily on achieving the first two horns of the energy trilemma, namely energy security and energy equity (Heffron, McCauley, and Rubens 2018). In particular, during the first wave of global electricity market restructuring that began in Chile, England and Wales, and Norway in the mid-1980s (Hogan 2002), policymakers aimed to improve both the operational and the economic efficiency of their energy systems (Conejo and Sioshansi 2018). Corresponding reforms intended to improve the ability of the energy system to provide consumers with electricity reliably (referring to energy security) and at low costs (referring to energy equity). Because people generally viewed fossil fuel-based power plants as being more reliable and cost-efficient than RESs, project developers have primarily invested in conventional generation capacity.

Today, as the negative consequences of fossil fuel-based electricity generation are becoming increasingly apparent in many countries, policymakers around the world are introducing new reforms to transform their energy systems from high-carbon into low-carbon systems; in particular, policymakers aim to replace conventional power plants with RESs. More than the first wave of electricity system reforms, international efforts such as the United Nation's Sustainable Development Goals (SDGs) or the 2015 Paris Agreement will accelerate these new reforms—putting additional external pressure on energy policymakers to make their energy systems more sustainable. Here, it is becoming increasingly apparent that the past improvements in energy security and energy equity came at the expense of the third horn of the energy trilemma, namely energy sustainability: the RES uptake is still slow in many countries, and this is particularly true for developing and emerging countries (Tabrizian 2019). Therefore, policymakers may rebalance the energy trilemma and place more emphasis on environmental sustainability if the RES uptake and the energy transition are to be successful.

One prime example of a country where a misfit of RES targets and actual policy reforms is apparent is Indonesia (Gunningham 2013). For many years, policymakers in Indonesia have relied on fossil power plants, mainly coal-fired power plants, to provide the population with reliable (i.e., energy security) and affordable (i.e., energy equity) electricity. Since Indonesia has not made much progress with regard to the liberalization described above, its current energy system is still heavily dependent on state control. As the country has considerable coal, gas, and oil resources, policymakers currently see fossil power plants as a low-cost way to generate electricity. In 2014, the government announced ambitious plans to increase the share of RESs in Indonesia's energy mix. Given these targets, reforms of Indonesia's energy system are now necessary to shift the country's emphasis from fossil fuels to RESs. However, the past reforms that the country undertook to make renewables more cost-competitive with conventional power plants have so far proven to be less successful in Indonesia (Ditjen EBTKE 2019). Therefore, the government is in search of clear policy directions to push the RES uptake in the coming years.

While the literature has discussed some small- to medium-scale reforms with respect to increasing the share of RESs in the Indonesian energy system (see, e.g., ADB 2019 or Burke et al. 2019), in our paper, we instead suggest and address a major reform of the Indonesian electricity sector, namely the introduction of an energy-only wholesale market for electricity that currently does not exist, and, in particular, a corresponding new electricity pricing system. The latter relates to the method of implementing wholesale prices, for instance in the form of a nodal pricing, a zonal pricing, or a uniform pricing system (Weibelzahl 2017). These three systems differ in the extent to which electricity trade accounts for the scarce transmission capacities of the network and whether post-trade redispatch is necessary. We rely on experiences from countries that have already successfully restructured their energy systems, including countries in Europe and the US. In particular, we draw on experiences from these countries regarding the benefits and challenges of each pricing system.

Central to our research is the idea that any major reform that aims at improving energy sustainability in Indonesia must also meet the other two ongoing major objectives of the government (i.e., energy security and energy equity). Hence, the focus of our research is on answering the following research question (RQ):

How can different electricity pricing systems support Indonesia in balancing its energy trilemma?

To answer our RQ, we develop an economic model that we base on analytical modeling and that allows us to analyze private and public investment decisions in liberalized electricity markets; that is, we consider both generation and transmission investments. In particular, we develop a model for each of the three standard pricing systems that have emerged from the first wave of electricity market restructuring, specifically nodal pricing, zonal pricing, and uniform pricing (Weibelzahl 2017). The three model variants allow us to examine and to compare the investments under each of the three pricing systems and the respective impact on the energy trilemma.

To illustrate the applicability of our model, we evaluate it with a simplified version of the Indonesian electricity network, focusing particularly on the Sumatra and Java–Bali electricity subnetworks. Subsequently, we discuss our results in the light of our RQ. In particular, we broaden the discussion toward an energy justice perspective on the energy trilemma, as Heffron, McCauley, and Rubens (2018) proposed. The concept of energy justice basically aims to enforce the observance of human rights across the entire energy life cycle. It has five forms at its core: distributive, procedural, recognition, restorative, and cosmopolitan justice (Heffron and McCauley 2017). Thus, we demonstrate the importance for Indonesian policymakers not only to improve energy sustainability but also to balance it with the interests of energy equity and energy security. Ultimately, we outline a first transformation pathway for a more sustainable and just transition to a low-carbon economy in Indonesia.

With our paper, we aim to contribute to research and practice in at least five ways. First, based on our models, we illustrate how the introduction of liberalized markets, and of market-based pricing in particular, may support countries like Indonesia in balancing the energy trilemma and in reaching goals concerning increased RES penetration. Second, building on the experiences from other countries that have already implemented market-based pricing mechanisms, our paper describes how the models may work in practice and specifically how they may work in Indonesia, an emerging lower-middle-income economy (World Bank 2020c). Third, our paper analyzes and discusses the first and preliminary results using a simplified network model of Indonesia (i.e., the introduction of markets and different electricity pricing systems) from an energy justice perspective. Fourth, our model may generally provide policy-relevant insights for investment institutions (e.g., for development banks or other investment funds) by supporting decisions on funding strategies concerning energy transition projects. Finally, our research demonstrates how reform in the electricity sector can result in more just outcomes for society from policy decisions that aim to develop a low-carbon economy.

The structure of the paper is as follows. Section 2 first presents the insights and experiences that we obtained from the existing literature on electricity pricing systems; second, it outlines the status quo of the Indonesian energy system and previous reform attempts. In Section 3, we develop our pricing models. Section 4 presents the data basis for the simplified Sumatra and Java–Bali electricity networks that we use in our evaluation. Section 5 discusses the results of our three pricing systems; in particular, we consider the results from an energy justice perspective on the energy trilemma. The penultimate section of our paper, Section 6, summarizes the implications for research and policymakers. Finally, Section 7 concludes the paper.

2. THEORETICAL BACKGROUND

This section provides the relevant background for our analysis: First, we provide a brief overview of electricity pricing systems in the context of the worldwide electricity market liberalization; second, we describe the current Indonesian energy sector and the respective policy reforms that build the basis for our model evaluation (see Sections 4–6).

2.1 Electricity Pricing Systems

Within the last decades, the worldwide era of liberalization has affected many energy systems (Pollitt 2012). In the case of electricity systems, restructuring has typically taken shape through the introduction of wholesale markets for electricity and the corresponding implementation of different electricity pricing systems (Weibelzahl 2017). Policymakers in Chile, England and Wales, and Norway were among the first to introduce wholesale markets for electricity (Hogan 2002); others in many more countries around the world followed their example. By introducing these new markets, policymakers aimed at improving both the operational and the economic efficiency of electricity sectors to be able to provide consumers with electricity reliably (i.e., energy security) and at low costs (i.e., energy equity) (Conejo and Sioshansi 2018). Not only by creating markets for free trade but also by breaking up vertically integrated monopolies, policymakers intended to foster competition, thereby lowering the prices and incentivizing private project developers to invest in generation capacity (Pollitt 2012).

Various forms of restructured electricity markets have emerged around the world. They typically have in common a transmission sector that remains highly regulated, as are the associated public network investments (Vogelsang 2006). However, there are differences, particularly with respect to how wholesale market trade is organized using different design options for trade between different market players, including electricity generating companies and consumers. The literature has mainly discussed three different electricity pricing systems, namely nodal pricing, zonal pricing, and uniform pricing (Gan and Bourcier 2002; Leuthold, Weigt, and Hirschhausen 2008; Weibelzahl 2017). These different pricing systems vary in the way in which they manage the limited transmission capacities of the network and in the way in which pricing rules take these scarce capacities into account.

Under a nodal pricing system, all the economic and physical restrictions of the system are perfectly "integrated"; that is, the market equilibrium takes the relevant production-related, consumption-related, and transmission-related constraints into account (Singh, Hao, and Papalexopoulos 1998). Therefore, the resulting node-specific prices adequately reflect the local and temporal scarcity in the form of price peaks; for more original work on nodal pricing, see, for example, Bohn, Caramanis, and

Schweppe (1984), Schweppe et al. (1988), Hogan (1992), and Chao and Peck (1996). In contrast, a zonal pricing system pools nodes into different pricing zones that share a common price (Bjørndal and Jørnsten 2001). Hence, the zonal system considers the physical restrictions between the assumed price zones while neglecting the intra-zonal transmission restrictions. This requires ex post redispatch of the transmission system operator (TSO) resulting from the relaxation of the relevant physical transmission rules within zones during spot market trade, as the responsible TSO may not be able to transport the produced electricity to the corresponding consumers. Therefore, redispatch takes place in a second step, restoring physical feasibility at minimal cost (Burstedde 2012; Egerer, Weibezahn, and Hermann 2016). In this context, redispatch refers to either the upregulation or the downregulation of different electricity generators to ensure feasible electricity flows in the network without an overflow on the transmission lines; for more original work on zonal pricing, see, for example, Bjørndal, Jørnsten, and Pignon (2003) and Oggioni and Smeers (2013). Finally, a uniform pricing system completely ignores the physical transmission constraints at the electricity exchange (Kahn et al. 2001). It accounts only for production-related and consumption-related constraints. As a direct consequence, redispatch takes place in a second step to deal with the corresponding transmission infeasibility.

The chosen pricing systems directly determine the profitability of private investments in new generation capacity. Obviously, while the investors/operators of a power plant receive no location-specific investment signals under a uniform pricing system, nodal prices reward investments in locations where the generation capacity is scarce to a greater extent. Nevertheless, the large number of different prices in a nodal pricing system makes it highly complex and electricity consumers may perceive it to be unfair, as people in different network locations will typically pay different prices. Ultimately, the issue of choosing an adequate pricing system is a highly complex decision for policymakers. For all three of the systems, there are valuable experiences regarding the benefits and challenges from countries that have already successfully liberalized their electricity markets, for example the US (currently using nodal pricing; see, e.g., Gil and Lin 2013), Norway (currently using zonal pricing; see, e.g., Bjørndal and Jørnsten 2001), and Germany (currently using uniform pricing; see, e.g., Müsgens, Ockenfels, and Peek 2014). Against this background, Table 1 summarizes some of the main benefits and challenges of the three different pricing systems that countries have experienced in the past.

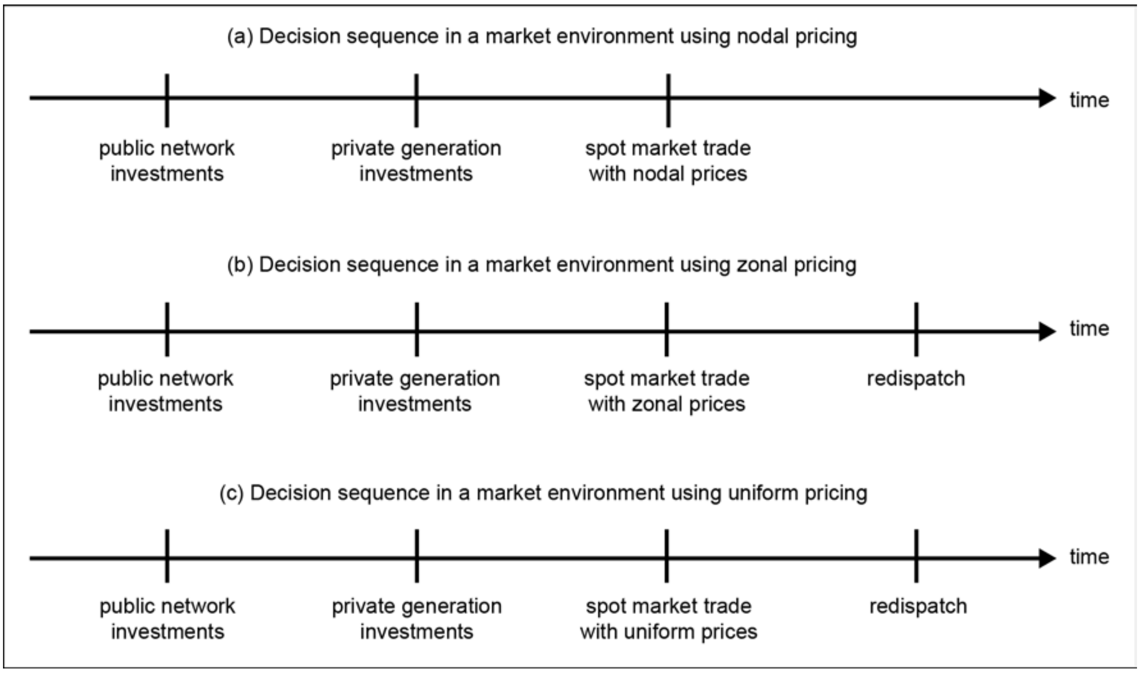
As already highlighted, the transmission sector is typically highly regulated, which implies that some kind of public entity often makes network investment decisions. In addition to the already high complexity of a pure cost–benefit analysis (with respect to the effects on the short-run network operation) of a possible network extension project, what complicates network investment decisions even more is the fact that they will generally affect electricity prices under the chosen pricing system. In turn, the price changes may influence private investments in new generation capacity, as described above. Therefore, the chosen pricing system will also have a severe impact on the question of which public network investments are necessary to avoid negatively affecting the investment behavior of private companies. Ultimately, this clearly highlights the high degree of interdependency of the different investment decisions and the many possible side effects associated with the introduction of a pricing system that policymakers can hardly anticipate without the help of quantitative economic models, such as the ones that we introduce in Section 3.

Table 1: Experiences with Different Pricing Systems

Pricing System	Benefits	Challenges
Nodal pricing	• Efficient dispatch of generation • Local signals/incentives in long-run investments • No redispatch necessary	• High system complexity • Many small submarkets with possibly low competition and market power abuse • Fluctuating local prices
Zonal pricing	• Reduced number of different prices • Increased intra-zonal competition • Price stability	• Possibly inefficient dispatch of power plants • Reduced signals for flexibility • No local signals/incentives for long-run investments • Difficult determination of zonal boundaries • Possibly high redispatch costs and associated reallocation issues • Defining adequate remuneration for redispatch services
Uniform pricing	• High market liquidity • Low system complexity • Relatively high competition • Price stability	• Possibly inefficient dispatch of power plants • Possibly inefficient long-run investments • Possibly high redispatch costs and associated reallocation issues

Source: Authors' creation from the review of Bjørndal and Jørnsten (2001), Gil and Lin (2013), Müsgens, Ockenfels, and Peek (2014), and Weibelzahl (2017).

Figure 1: Decision Sequences under Different Pricing Systems



Source: Authors' creation.

To give an overview of the relevant public and private decision making under each of the three pricing systems, we illustrate the corresponding decision sequences accounting for both long-run investment decisions and short-run market clearing in Figure 1. Here, public network investment choices (decision level 1) are followed by expected private generation investments and spot market trade (decision level 2).

In the case of zonal and uniform pricing, spot market trade is followed by redispatch of the TSO (decision level 3) to restore the transmission feasibility.

2.2 The Indonesian Energy System

Given the different pricing systems, our paper investigates how these pricing systems may support Indonesia in increasing its RES generation. Therefore, we provide a brief overview of the Indonesian energy sector.

With more than 267 million citizens, Indonesia is the world's fourth most populous country (World Bank 2019b). It has the biggest economy in Southeast Asia and ranks 16th among the world's economies in terms of total GDP (World Bank 2019a). Positioned between the Indian Ocean and the Pacific Ocean, Indonesia is additionally the world's biggest island state, consisting of 17,508 islands, around 6,000 of which are inhabited. With respect to its electricity sector, the term "archipelago" perfectly describes the Indonesian electricity network, which consists of eight major and around 600 isolated networks (Burke et al. 2019). During the first wave of global electricity market restructuring, Indonesia made its first privatization efforts by opening its electricity generation sector to independent power producers (IPPs) in the 1990s (Maulidia et al. 2019). Today, however, there are only a few IPPs in Indonesia and the liberalization appears to be incomplete. In particular, the state-owned enterprise *Perusahaan Listrik Negara* (PLN) and its subsidiaries still own more than 75% of the generation capacity in the country (Maulidia et al. 2019). No further significant privatization has taken place, which is why—except for electricity generation—the state controls Indonesia's electricity sector; that is, PLN controls the network and sells electricity to consumers (Burke et al. 2019). The current organization of the Indonesian electricity sector is as a single-buyer market (Sakya et al. 2006). Typically, under such a market design, countries preserve an artificial monopoly over the electricity sector even after formally unbundling the vertically integrated state-owned enterprise (i.e., PLN in Indonesia) (Lovei 2000). In fact, PLN buys all the electricity produced in Indonesia (as a single buyer) and resells it to electricity consumers at regulated prices.

In terms of energy security, Indonesia has struggled to provide its citizens with access to electricity and has performed poorly for many years in this respect compared with other Southeast Asian countries (Maulidia et al. 2019). In 2010, roughly 14 million Indonesians (i.e., 5.85% of the population) had no access to electricity (World Bank 2020a), which is why improving the electrification rate has been a key priority of policymakers in the past decade (Maulidia et al. 2019). Indeed, by 2017, the electrification rate had improved: now only 4.9 million Indonesians (i.e., 1.86% of the population) are without electricity access (World Bank 2020a). However, this number is misleading. First, electrification varies from region to region in Indonesia. For example, while the electrification rate is 100% in Java, outside of Java it is only 90.45%; in regions like Papua (42.5%) or Jambi (51.91%), the electrification rate is significantly lower (PT PLN 2019a). Second, power cuts are frequent for many Indonesians across all regions (Gunningham 2013). The Indonesian electricity network is still very unreliable since there is a lack of generation and network capacity.

In terms of energy equity, Indonesia is making efforts to keep retail prices low for its citizens to combat poverty. In 2010, roughly 38 million Indonesians (i.e., 15.7%) lived in poverty, that is, on $1.90 a day (World Bank 2020b). Against this background, ensuring low retail prices for electricity was and still is a key measure for the Indonesian Government in its fight against poverty (Maulidia et al. 2019). This is why retail prices are set by the government in Indonesia, as described above. To improve both energy security and energy equity, Indonesia's policymakers have focused on the expansion of fossil power plants—above all, coal-fired power plants. Here, the policymakers base their rationale on the supposed advantages of coal over other options. Not only does Indonesia have large domestic coal reserves, but also its coal-fired power plants are capable of providing the necessary base load power (Gunningham 2013). Further, policymakers view coal-fired power plants as being easy to finance and quick to build. To support the domestic production and thereby ensure an adequate electricity supply and lower the costs of electricity production, the government ultimately subsidizes fossil fuels like coal or oil.

This focus on an energy supply chain based on fossil fuels has resulted in a situation that mainly neglects the third horn of the energy trilemma, energy sustainability, in Indonesia. Today, RESs like solar or wind power only make up a fraction of Indonesia's energy mix—despite the country having huge renewable potential (Dutu 2016). Only in 2014 did the government announce ambitious goals to develop RESs in Indonesia: compared with 6% in 2014, RESs are to account for 23% of the energy mix by 2025 and even 31% by 2050 (Maulidia et al. 2019). However, recent estimates have suggested that Indonesia will not reach its 2025 and 2050 goals at the current RES development rates (Burke et al. 2019). One of the key barriers to RES development is that the current design of the Indonesian energy system does not allow RESs to become competitive with fossil power plants (Burke et al. 2019; Maulidia et al. 2019). What is therefore necessary is a fundamental reform of the energy system so that Indonesia is able to achieve its RES targets—and avoids ending up locked into a fossil fuel future (Liebman et al. 2019).

Indeed, the Indonesian Government has launched a series of reforms over the past ten years to strengthen RESs. However, these reforms were not very successful in terms of the market penetration of RESs. For example, within the last ten years, the Ministry of Energy and Mineral Resources (MEMR) has made repeated efforts to push the development of solar PV in Indonesia. From 2013 onwards, the MEMR tried to improve the situation for developers through five key regulations (i.e., No. 17/2013, 19/2016, 12/2017, 50/2017, and 4/2020) (Kennedy 2018). In 2013, the MEMR introduced the first auction program for solar PV in Indonesia (Reg. No. 17/2013) (MEMR 2013). Although the program covered 140 MW in over 80 locations, it only realized two projects due to protests from PLN and local manufacturers, who opposed the favorable tariffs for solar PV developers. Moreover, it was not private investors but rather two state-owned companies that implemented the two actually realized projects (Kennedy 2018).

In 2016, the MEMR introduced a feed-in tariff for solar PV projects, collectively covering at least 5,000 MW (Reg. No. 19/2016) (MEMR 2016). However, the regulation included restrictions on the project size and foreign ownership, discouraging international developers. Only a couple of months later, it abandoned these feed-in tariffs (Kennedy 2018). Instead, from 2017 onward, the MEMR regulated the tariffs that solar PV developers can charge to PLN (Reg. No. 12/2017) (MEMR 2017b), basing tariffs on and limiting them to a maximum of 85% of the local and national average costs of generation. In addition, it differentiated them geographically (Kennedy 2018). Reacting to stakeholders' new protests, it eventually replaced Reg. No. 12/2017 with Reg. No. 50/2017 (MEMR 2017a). One major difference between the two regulations is that the new one forced RES developers to transfer ownership of their facilities to PLN on completion of power purchase agreements. In combination with the tariff limits, the situation for investments in RES plants was not attractive in terms of recovering project costs (Kennedy 2018). In 2020, the MEMR introduced Reg. No. 4/2020, which stipulates amendments for Reg. No. 50/2017 to overcome key items in Reg. No. 50/2017 that had become barriers to RES development (e.g., at the end of power purchase agreements, IPPs no longer had to transfer the ownership of their facilities to PLN). The amendments provide more flexibility for investors and aim to accelerate RES growth in Indonesia.

To summarize, Indonesia's energy policy to promote RES development to date has suffered from several major changes in direction (e.g., the shift from feed-in tariffs to regulated tariffs) as well as from an overall tendency to retain at least some state control over new projects. The government's RES development strategy has therefore not proven to be successful so far. Ultimately, the government is in search of clear policy directions to promote an increase in the number of RES plants in the coming years. In the next section, we will therefore develop a model to assess the impacts of a major reform in Indonesia that builds on the introduction of an energy-only wholesale market.

3. MODEL DEVELOPMENT

3.1 Notation and Economic Quantities

In this section, we first introduce the economic set-up for the three pricing models of nodal, zonal, and uniform pricing, which we will present in more detail in Section 3.2. Table 4, Table 5, and Table 6 in Appendix 1 provide a short summary of the main sets, parameters, and variables that we use in our paper.

3.1.1 Planning Horizon and Electricity Network

$T = \{1, \dots, |T|\}$ describes the finite planning horizon. In addition, we assume an electricity network $\mathcal{G} = (N, L)$ that consists of a set of network nodes N and a set of transmission lines L interconnecting the different nodes.

We describe each transmission line $l \in L$ using its maximal transmission capacity $\bar{f}_l$ and its susceptance B_l. Accounting for possible network investments from a public entity like a responsible TSO, the subset $L^{\text{new}} \subseteq L$ collects all the candidate transmission lines for the responsible TSO's investments. In analogy, subset $L^{\text{ex}} \subseteq L \setminus L^{\text{new}}$ collects all the existing transmission lines of network $\mathcal{G}$.

As new transmission lines are typically characterized by high fixed costs, we model network investments as zero–one decisions using a binary variable $w_l \in \{0, 1\}$. The latter is equal to one if and only if the TSO builds $l \in L^{\text{new}}$. The given cost parameter i_l describes investments in line l.

3.1.2 Electricity Demand

$C \subseteq N$ collects all the nodes of the network containing electricity consumers. We assume an elastic long-term demand for each time period t and demand node $c \in C$ using the following linear demand function:

$$\pi_{ct}(d_{ct}) = a_{ct} - b_c d_{ct} \quad \forall c \in C, t \in T. \tag{1}$$

In the inverse demand function (1), d_{ct} denotes the endogenous demand quantity of consumer c in time period t while a_{ct} and b_c are the ex ante given parameters that specify the actual demand function. $\pi_{ct}(d_{ct})$ gives the resulting prices for a given quantity of d_{ct}. We note that the assumption of an elastic demand is quite common in the electricity market literature; see, for example, Chao and Peck (1996), Bjørndal and Jørnsten (2001), Bjørndal, Jørnsten, and Pignon (2003), Ehrenmann and Smeers (2005), Bjørndal and Jørnsten (2007), Pechan (2017), or Weibelzahl and Märtz (2020).

Using the above demand function, the following gives the gross consumer surplus, which describes the aggregated monetary consumer benefits:

$$\sum_{t\in T}\sum_{c\in C}\int_0^{d_{ct}}\pi_{ct}(h)dh=\sum_{t\in T}\sum_{c\in C}\left(a_{ct}-\frac{b_c}{2}d_{ct}\right)d_{ct}. \qquad (2)$$

3.1.3 Electricity Generation

Renewable Electricity Generators

Let us use a set of carbon-neutral, renewable electricity generators R. The subset $R_n \subseteq R$ comprises all the renewable generators that are located at network node $n \in N$.

We assume that the set of generators R consists of both existing and candidate generators; that is, we partition the set of renewable generators R into a set of existing generators R^{ex} and a set of candidate generators R^{new}. Corresponding investments of i_r per unit of installed generation capacity $\bar{y}_r^{\mathrm{new}}$ arise for each candidate generator. In analogy, $\bar{x}_r^{\mathrm{ex}}$ describes the installed capacity of an existing generator.

Accounting for fluctuations in power production, for each generator r, we assume relative availability $\alpha_{rt} \in [0,1]$ of electricity generation capacity in time period t. As this parameter refers to the relative availability of the corresponding resources, like wind or sun, it depends both on the time period t and on the location of the generator; for example, at night, there will be no sun, meaning that there is availability of zero. Thus, in each time period and for each renewable generator, $\alpha_{rt}\bar{x}_{rt}$ limits the maximum electricity output. Given this capacity bound, we then model the actually chosen electricity output using the variable $x_{rt} \geq 0$. $v_r \geq 0$ describes the variable per-unit production costs.

Conventional Electricity Generators

Set G contains all the conventional electricity generators in the system. Analogous to the renewable generators above, we describe with $G_n \subseteq G$ the subset of conventional electricity generators located at network node $n \in N$.

We describe generator $g \in G$ using its variable per-unit production cost $v_g \geq 0$. The endogenous variable $y_{gt} \geq 0$ gives the realized electricity output of generator g in period t. Similar to renewable generators, we partition the set of conventional generators G into a set of pre-existing generators G^{ex} and a set of candidate generators G^{new}. It is possible to invest in the latter with investments of i_g per unit of installed generation capacity $\bar{y}_g^{\mathrm{new}}$. For all existing generators, the corresponding generation capacity is $\bar{y}_g^{\mathrm{ex}}$.

3.2 Modeling Different Pricing Systems

In the following, we develop the models for the three different pricing systems; see also Grimm et al. (2016) and Weibelzahl and Märtz (2020) for similar models. In particular, we will present step by step the decision levels (hereinafter levels) under each of the pricing systems according to Figure 1 in Section 2.1. From a mathematical point of view, our models represent multilevel optimization problems, in which the different players anticipate the optimal decisions that the other players take on subsequent levels; for example, the TSO chooses the optimal line investments on the first level, forming expectations of the optimal private generation investments, spot market outcomes, and necessary redispatch interventions on the subsequent levels.

The formulation of the public network investments of the TSO, that is, decision level 1 (see Section 3.2.1), is identical for all three of the systems. As decision level 2, that is, expected private generation investments and spot market trade, as well as decision level 3, that is, necessary redispatch of the TSO, differ for each of the systems, we model these levels in system-specific sections (see Sections 3.2.2, 3.2.3, and 3.2.4).

3.2.1 Public Network Investments of the TSO (Decision Level 1)

On the first level and for all three pricing systems, we assume a benevolent TSO that chooses a network expansion plan that maximizes the welfare of the whole system:

$$\begin{aligned}\max \sum_{c\in C}\sum_{t\in T}\int_0^{d_{ct}} \pi_{ct}(h)\mathrm{d}h - \sum_{r\in R}\sum_{t\in T} v_r x_{rt} - \sum_{g\in G}\sum_{t\in T} v_g y_{gt} - \sum_{g\in R^{\mathrm{new}}} i_r \bar{x}_r \\ - \sum_{g\in G^{\mathrm{new}}} i_g \bar{y}_g - \sum_{l\in L^{\mathrm{new}}} i_l w_l\end{aligned} \tag{3}$$

The TSO accounts for the integrality of its network investment decisions and expects optimal private generation investments as well as spot market (and redispatch) outcomes of the subsequent levels (see also the following sections).

$$w_l \in \{0,1\} \quad \forall l \in L^{\mathrm{new}}. \tag{4}$$

3.2.2 Nodal Pricing (Decision Level 2)

On the second level, we model the investment and spot market bidding of perfectly competitive companies for a nodal pricing system; see, for example, Boucher and Smeers (2001), Daxhelet and Smeers (2007), Grimm et al. (2016), and Weibelzahl (2017) for the assumption of perfect competition on electricity markets. As a well-known and established standard in the literature, perfect competition allows us to formulate investment and market clearing as a single welfare maximization problem given the above network investments of the TSO:

$$\max \sum_{c \in C} \sum_{t \in T} \int_0^{d_{ct}} \pi_{ct}(h) \mathrm{d}h - \sum_{r \in R} \sum_{t \in T} v_r x_{rt} - \sum_{g \in G} \sum_{t \in T} v_g y_{gt} - \sum_{g \in R^{new}} i_r \bar{x}_r - \sum_{g \in G^{new}} i_g \bar{y}_g \tag{5}$$

We first require a nodal flow balance according to

$$d_{nt} = \sum_{r \in R_n} x_{rt} + \sum_{g \in G_n} y_{gt} + \sum_{l \in \delta_n^{\text{in}}(L)} f_{lt} - \sum_{l \in \delta_n^{\text{out}}(L)} f_{lt} \quad \forall n \in N, t \in T, \tag{6}$$

where $\delta_n^{\text{in}}(L)$ and $\delta_n^{\text{out}}(L)$ collect all the ingoing and outgoing lines of node *n*, respectively. In addition, all the power flows must account for their lower and upper flow bounds:

$$-\bar{f}_l \leq f_{lt} \leq \bar{f}_l \quad \forall l \in L^{\text{ex}}, t \in T, \tag{7}$$

$$-\bar{f}_l w_l \leq f_{lt} \leq \bar{f}_l w_l \quad \forall l \in L^{\text{new}}, t \in T. \tag{8}$$

According to Kirchhoff's Laws, the following determines the power flows on the different transmission lines:

$$f_{lt} = B_l(\theta_{nt} - \theta_{mt}) \quad \forall l = (n, m) \in L^{\text{ex}}, t \in T, \tag{9}$$

$$-M(1 - w_l) \leq f_{lt} - B_l(\theta_{nt} - \theta_{mt}) \leq M(1 - w_l) \quad \forall l = (n, m) \in L^{\text{new}}, t \in T. \tag{10}$$

In the above constraints, θ_{nt} gives the phase angle at node *n* in time period *t*. In addition, parameter *M* is a sufficiently large constant that we denote as big-M.

The phase angle of reference node 1 is set to zero, ensuring unique phase angle values in the electricity system:

$$\theta_{1t} = 0 \quad \forall t \in T. \tag{11}$$

Given the current weather conditions together with the private generation investments undertaken, the power production is limited according to:

$$0 \leq x_{rt} \leq \alpha_{rt} \bar{x}_r^{\text{ex}} \quad \forall r \in R^{\text{ex}}, t \in T, \tag{12}$$

$$0 \leq x_{rt} \leq \alpha_{rt} \bar{x}_r^{\text{new}} \quad \forall r \in R^{\text{new}}, t \in T, \tag{13}$$

$$0 \leq y_{gt} \leq \bar{y}_g^{\text{ex}} \quad \forall g \in G^{\text{ex}}, t \in T, \tag{14}$$

$$0 \leq y_{gt} \leq \bar{y}_g^{\text{new}} \quad \forall g \in G^{\text{new}}, t \in T \tag{15}$$

Finally, all the investment variables $\bar{x}_r^{\text{new}}$, $\bar{y}_g^{\text{new}}$ must be non-negative:

$$\bar{x}_r^{\text{new}} \geq 0 \quad \forall r \in R^{\text{new}}, \tag{16}$$

$$\bar{y}_g^{\text{new}} \geq 0 \quad \forall g \in G^{\text{new}}. \tag{17}$$

3.2.3 Zonal Pricing (Decision Levels 2 and 3)

Spot Market Trade and Private Investments in New Generation Capacities

In the case of zonal pricing, we partition the node set N into k connected, non-empty price zones $Z_1, \dots, Z_k$. $\mathcal{Z} = \{1, \dots, k\}$ gives the set of price zone indices, for which the responsible public entities, for example regulators, governments, or TSOs, specify k ex ante. In the following, we assume transfer capacity-based market coupling, that is, we use only restrictions relating to the available transfer capacities between zones. As a consequence, the zone-specific prices do not account for possible intra-zonal network congestion, but companies exclusively receive price signals incentivizing them not to exceed the inter-zonal transmission capacities. For the ease of notation, we let L^{inter} be the set of all inter-zone transmission lines. Again, we model the optimal investment behavior and market clearing as a single welfare maximization problem:

$$\begin{aligned} \max \sum_{c \in C} \sum_{t \in T} \int_0^{d_{ct}} \pi_{ct}(h) \mathrm{d}h - \sum_{r \in R} \sum_{t \in T} v_r x_{rt} - \sum_{g \in G} \sum_{t \in T} v_g y_{gt} - \sum_{g \in R^{\text{new}}} i_r \bar{x}_r \\ - \sum_{g \in G^{\text{new}}} i_g \bar{y}_g. \end{aligned} \tag{18}$$

In contrast to nodal flow balance, we now only require zonal flow balance:

$$\sum_{n \in Z_i} d_{nt} = \sum_{n \in Z_i} \left(\sum_{r \in R_n} x_{rt} + \sum_{g \in G_n} y_{gt} + \sum_{l \in \delta_{Z_i}^{\text{in}}(L)} f_{lt} - \sum_{l \in \delta_{Z_i}^{\text{out}}(L)} f_{lt} \right) \forall i \in \mathcal{Z}, t \in T. \tag{19}$$

The following restrict the power flows on inter-zonal transmission lines:

$$-\bar{f}_l \leq f_{lt} \leq \bar{f}_l \quad \forall l \in L^{\text{ex}} \cap L^{\text{inter}}, t \in T, \tag{20}$$

$$-\bar{f}_l w_l \leq f_{lt} \leq \bar{f}_l w_l \quad \forall l \in L^{\text{new}} \cap L^{\text{inter}}, t \in T. \tag{21}$$

Again, given the current weather conditions and the generation investment, the power production must be feasible:

$$0 \leq x_{rt} \leq \alpha_{rt}\bar{x}_r^{\text{ex}} \quad \forall r \in R^{\text{ex}}, t \in T, \tag{22}$$

$$0 \leq x_{rt} \leq \alpha_{rt}\bar{x}_r^{\text{new}} \quad \forall r \in R^{\text{new}}, t \in T, \tag{23}$$

$$0 \leq y_{gt} \leq \bar{y}_g^{\text{ex}} \quad \forall g \in G^{\text{ex}}, t \in T \tag{24}$$

$$0 \leq y_{gt} \leq \bar{y}_g^{\text{new}} \quad \forall g \in G^{\text{new}}, t \in T \tag{25}$$

Finally, as with nodal pricing, all the investment variables must be non-negative:

$$\bar{x}_r^{\text{new}} \geq 0 \quad \forall r \in R^{\text{new}}, \tag{26}$$

$$\bar{y}_g^{\text{new}} \geq 0 \quad \forall g \in G^{\text{new}}. \tag{27}$$

Redispatch

On the redispatch level, the TSO redispatches the contracted spot market volumes, restoring the feasibility of power flows while minimizing the arising redispatch costs. Here, the final quantities after redispatch may be smaller than, equal to, or larger than the pre-redispatch quantities, that is, the contracted spot market quantities. Throughout the paper, we indicate redispatch adjustments with Δ; for example, $\Delta_{y_{1,2}} = 5$ indicates that the TSO asks conventional power generator 1 to increase its production by 5 units in period 2. In the following, we will use a cost-based redispatch mechanism that is, for instance, in use in Germany. Under such a mechanism, redispatch is profit neutral and only accounts for additional or saved costs associated with a redispatch intervention to avoid gaming problems or market power abuse. We can therefore state the redispatch cost minimization for given spot market outcomes as

$$\min \sum_{t \in T} \left(\sum_{c \in C} \int_{d_{ct}+\Delta d_{ct}}^{d_{ct}} \pi_{ct}(h)\mathrm{d}h + \sum_{r \in R} v_r \Delta x_{rt} + \sum_{g \in G} v_g \Delta y_{gt} \right), \tag{28}$$

where we also assume that redispatch can apply to both producers and consumers.

Similar to the above nodal pricing formulation, power balance is imposed for each node on the redispatch level:

$$\begin{aligned} d_{nt} + \Delta d_{nt} = \sum_{r \in R_n} (x_{rt} + \Delta x_{rt}) + \sum_{g \in G_n} (y_{gt} + \Delta y_{gt}) \\ + \sum_{l \in \delta_n^{\text{in}}(L)} (f_{lt} + \Delta f_{lt}) - \sum_{l \in \delta_n^{\text{out}}(L)} (f_{lt} + \Delta f_{lt}) \end{aligned} \quad \forall n \in N, t \in T. \tag{29}$$

After redispatch, all the power flows must be physically feasible:

$$-\bar{f}_l \leq f_{lt} + \Delta f_{lt} \leq \bar{f}_l \quad \forall l \in L^{\mathrm{ex}}, t \in T, \tag{30}$$

$$-\bar{f}_l w_l \leq f_{lt} + \Delta f_{lt} \leq \bar{f}_l w_l \quad \forall l \in L^{\mathrm{new}}, t \in T, \tag{31}$$

$$f_{lt} + \Delta f_{lt} = B_l(\theta_{nt} - \theta_{mt}) \quad \forall l = (n,m) \in L^{\mathrm{ex}}, t \in T, \tag{32}$$

$$\begin{aligned}-M(1-w_l) \leq f_{lt} + \Delta f_{lt} - B_l(\theta_{nt} - \theta_{mt}) \\ \leq M(1-w_l)\end{aligned} \quad \forall l = (n,m) \in L^{\mathrm{new}}, t \in T, \tag{33}$$

$$\theta_{1t} = 0 \quad \forall t \in T. \tag{34}$$

Finally, when choosing the optimal redispatch, the TSO must take both the private generation investments and the exogenous weather conditions into account:

$$0 \leq x_{rt} + \Delta x_{rt} \leq \alpha_{rt} \bar{x}_r^{\mathrm{ex}} \quad \forall r \in R^{\mathrm{ex}}, t \in T, \tag{35}$$

$$0 \leq x_{rt} + \Delta x_{rt} \leq \alpha_{rt} \bar{x}_r^{\mathrm{new}} \quad \forall r \in R^{\mathrm{new}}, t \in T, \tag{36}$$

$$0 \leq y_{gt} + \Delta y_{gt} \leq \bar{y}_g^{\mathrm{ex}} \quad \forall g \in G^{\mathrm{ex}}, t \in T, \tag{37}$$

$$0 \leq y_{gt} + \Delta y_{gt} \leq \bar{y}_g^{\mathrm{new}} \quad \forall g \in G^{\mathrm{new}}, t \in T. \tag{38}$$

3.2.4 Uniform Pricing (Decision Levels 2 and 3)

Spot Market Trade and Private Investments in New Generation Capacities

It is possible to view uniform pricing as a special case of the above zonal pricing model in which we only have a single price zone, that is, $k = 1$. As a direct consequence, we have the same model as in Section 3.2.3 except for the fact, instead of zonal balance, we have a single market-clearing constraint for the whole market:

$$\sum_{n \in N} d_{nt} = \sum_{r \in R} x_{rt} + \sum_{g \in G} y_{gt} \quad \forall t \in T. \tag{39}$$

Redispatch

Similar to the case of zonal pricing, uniform pricing will also in general require redispatch to ensure transmission feasibility. Such redispatch can be modeled in the same way as in Section 3.2.3.

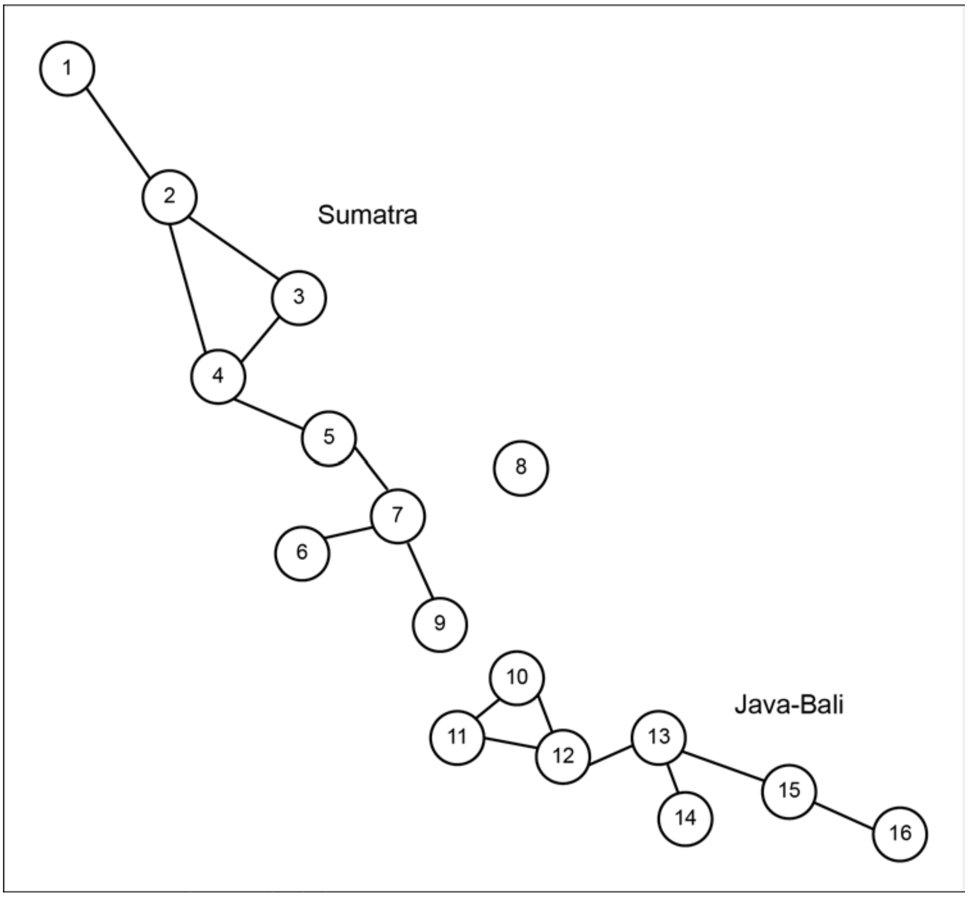
4. DATA AND EVALUATION SET-UP

In this section, we apply the models that we developed in Section 3 to a simplified representation of the Indonesian electricity sector. In particular, we restrict our analysis to the electricity systems of Sumatra and Java–Bali. Subsequently, we briefly outline the data basis for our computations; we provide additional information on the data that we use in Appendix 2.

4.1 Electricity Network

Our network of Sumatra and Java–Bali consists of 16 nodes: one node per province in the geographical units of Sumatra and Java and one node for Bali in the geographical unit of the Lesser Sunda Islands; see also Table 6 in Appendix 2. We based our data and assumptions concerning the existing transmission lines on IESR (2019a) and MEMR (2019). Currently, the two islands of Sumatra and Java–Bali are not connected. We allowed investments in new lines between neighboring nodes, as well as between nodes 6, 7, and 9 (Sumatra) and nodes 10, 11, and 12 (Java), to enable a possible interconnection between the two islands. For the cost parameters of network investments, we referred to Chang and Li (2015). Figure 2 illustrates our network topology with the considered nodes and lines.

Figure 2: Network Topology Illustrating the Considered Nodes and Lines



Source: Authors' creation.

4.2 Electricity Generation

We based the data concerning the existing generation capacities on PLN's 2018 *Rencana Usaha Penyediaan Tenaga Listrik* [Power Supply Business Plan] (PT PLN 2018); see Table 7 in Appendix 2 for an overview of the existing generation capacities located at each node. We considered all the power plants that are currently installed as existing power plants in our model. As Table 8 shows, currently around 88% of the installed generation capacity relates to conventional power plants, with coal-fired power plants accounting for 53% of the total installed generation capacity. Table 8 in Appendix 2 summarizes the assumptions concerning the techno-economic parameters of each generation technology. Except for coal-fired power plants, we allowed investments in new generation units at all nodes. We restricted investments in new coal-fired power plants to those nodes where coal-fired power plants are currently at the planning or construction stages, that is, nodes 2, 7, 9, 12, 13, and 16 (Global Energy Monitor 2020). This approach in particular aimed to exclude the possibility of building coal-fired power plants in regions where this is probably not possible due to real-life restrictions, such as geographical conditions or political resistance to coal-fired power plants. For investments in RESs, we set limits that determine the maximum amount of cumulated capacity that it is possible to invest in at each node. We intended these limits to reflect the respective potentials of each RES technology in each province; we took these data from Ditjen EBTKE (2016).

4.3 Electricity Demand

As we could not observe the real-world electricity demand functions of consumers in Indonesia because the government still sets the prices, we calibrated hourly demand functions for a representative day (with 24 hourly time intervals) at each node. Here, we based our derivation of demand functions on the cumulative annual demand at each node (PT PLN 2019b), the average retail price at each node (PT PLN 2019a), the characteristics of a typical daily load curve of the Java–Bali electricity sector (Batih and Sorapipatana 2016), and the long-term price elasticity of demand of Indonesian consumers (Burke and Kurniawati 2018). We assume here that the demand curves that we calculated tend to be a rather conservative estimate—the actual demand could therefore be higher.

5. RESULTS

In this section, we present the computational results of our evaluation (i.e., for the Sumatra and Java–Bali electricity sectors). For a detailed analysis and discussion of the results, see Section 6. We implemented the three pricing systems using the modeling language Zimpl (see Koch 2004) and used SCIP 6.0.2 (see Gleixner et al. 2018) to generate corresponding mps files. We then solved the problems with the CPLEX 12.10 solver (see IBM 2019). Given the corresponding results, we then calculated various key indicators for all three pricing systems. In particular, we computed (1) the welfare level and the consumer surplus, (2) private generation investments, (3) public network investments, (4) redispatch costs, and (5) resulting electricity prices; see Table 2 for an overview of the main computational results of the three models. For the zonal pricing system, we partitioned the 16 nodes into two price zones, in which nodes 1–9 belong to one price zone (hereinafter: "Sumatra") and nodes 10–16 belong to another price zone (hereinafter: "Java–Bali"). This partition reflects the two islands of Sumatra and Java–Bali (see Figure 2).

Table 2: Computational Results for All Three Pricing Systems; All Values Except for Normalized Welfare and Electricity Prices Are Rounded to Full Values

		Pricing System		
	Unit	**Nodal**	**Zonal**	**Uniform**
Normalized welfare	%	100	99.34	94.06
Absolute welfare	$	65,881,637	65,446,813	61,968,708
Consumer surplus	$	83,211,566	82,540,830	81,128,565
Redispatch costs	$	–	1,123,400	4,514,538
Aggregated renewable capacity added	MW	54,153	56,162	64,406
Aggregated conventional capacity added	MW	19,435	16,123	7,105
Overall generation capacity added	MW	73,588	72,285	71,511
Aggregated network capacity added	MW	3,000	4,400	12,544
Number of lines added	-	3	5	13
Aggregated renewable investment	$	7,864,540	8,403,509	10,646,770
Aggregated conventional investment	$	2,706,683	2,245,415	989,516
Aggregated network investment	$	216,000	316,800	903,168
Average electricity price	$/MWh	29.06	31.33	32.45
– for consumers in price zone “Sumatra”	$/MWh	26.21	30.28	32.45
– for consumers in price zone “Java–Bali”	$/MWh	32.72	32.69	32.45
Aggregated renewable generation	MWh	450,705	466,524	430,912
Aggregated conventional generation	MWh	248,025	218,583	222,275
Aggregated electricity consumption	MWh	698,730	685,107	653,187

Abbreviations: MW = megawatt, MWh = megawatt-hour.

Source: Authors’ creation.

First, we calculated the welfare levels realized under the three pricing systems (i.e., we calculated the aggregated difference between the consumer surplus and all the costs of production and investments). In line with the literature that considered nodal pricing to be the most efficient in terms of welfare (Weibelzahl 2017), we normalized the realized welfare under the nodal pricing system to 100%. Our results illustrate that the welfare decreases when pooling nodes into one or more zones: under zonal and uniform pricing, the normalized welfare is 99.34% and 94.06%, respectively. However, when comparing the uniform with the zonal pricing system, our results illustrate that market splitting (i.e., introducing two price zones) increases welfare. In addition to the welfare levels, we computed the (gross) consumer surpluses under each pricing system (i.e., the monetary benefits for consumers). Here, the order is the same as before, with nodal pricing yielding the highest and uniform pricing yielding the lowest consumer surplus. While we noted that the levels of welfare and consumer surplus do not differ enormously over the three pricing systems, our results highlight a clear decreasing trend of welfare and consumer surplus from nodal over zonal to uniform pricing.

Second, we computed the private investments in renewable and conventional generation. With respect to renewables, the maximum capacity of 64,406 MW occurs under the uniform pricing system. The zonal and nodal pricing systems show approximately 8,000–10,000 MW less of renewables, with 56,162 MW and 54,153 MW, respectively. With respect to conventional generators, the order is exactly the opposite: 19,435 MW under the nodal pricing system, 16,123 MW under the zonal pricing system, and only 7,105 MW under the uniform pricing system.

Third, we calculated the corresponding network investments. Under the nodal pricing system, there are three transmission lines; under the zonal pricing system, there are five transmission lines; and under the uniform pricing system, there are 13 lines. Moreover, our results illustrate that, under all three pricing systems, transmission lines connect the two islands of Sumatra and Java-Bali. It is possible to explain the considerably higher number of lines under the uniform pricing system by referring to the decision levels of the three models: under the uniform pricing system, private firms cannot and/or do not take network constraints into account and make their investment decisions independently from these constraints, meaning that they consider the network as a "copperplate" (Weibelzahl 2017) and do not receive location-specific investment signals. Accordingly, the TSO must adapt the network to the anticipated higher generation level and invest in the appropriate lines to transport electricity to the respective consumers. The respective redispatch costs also reflect this.

Fourth, we compute the redispatch costs. Under uniform pricing, the redispatch costs are roughly four times higher than the redispatch costs under zonal pricing. Following a similar logic as with the number of constructed lines, the higher redispatch costs that we observed under uniform pricing again result from private firms completely ignoring the network constraints when making their investment decisions. In contrast, while private firms do not consider the intra-zonal network constraints under zonal pricing, they nevertheless account for the inter-zonal network constraints. Therefore, in line with the literature (Ding and Fuller 2005), the redispatch costs are lower under the zonal pricing system than under the uniform pricing system.

Fifth, we calculated the resulting electricity prices for the three pricing systems. On average (i.e., over all nodes and time periods), consumers pay the lowest electricity price under the nodal pricing system, followed by the zonal pricing system. The highest average electricity price occurs under the uniform pricing system; see Section 6.2 for a more in-depth analysis and discussion of the resulting electricity prices.

6. DISCUSSION AND IMPLICATIONS

In this section, we discuss our results and derive implications for policy and research. In particular, we examine the results from three perspectives. First, we address our RQ and discuss how the three pricing systems may support Indonesia in balancing its energy trilemma. Second, we broaden our discussion toward an energy justice perspective on the energy trilemma. Finally, we summarize the implications that follow the previous steps and highlight a transition path for Indonesia toward a just low-carbon energy system.

6.1 Balancing Indonesia's Energy Trilemma

To date, as Section 2.2 discussed in detail, Indonesian policymakers have traditionally focused on energy security and energy equity. In 2014, by announcing its ambitious goals to develop RESs, the government demonstrated its political will to put more emphasis on the previously neglected third horn of the energy trilemma, namely energy sustainability. In line with our RQ, our primary aim in this paper is to investigate how the introduction of a wholesale market for electricity, and of different electricity pricing systems in particular, may support Indonesia in balancing its energy trilemma. Hence, we analyze and discuss the impacts of the three pricing systems on the horns of the energy trilemma in the following.

6.1.1 Energy Sustainability

This horn of the energy trilemma emphasizes the impacts of all energy-related activities on the environment. Assuming that RESs in general have a less damaging impact on the environment than conventional power plants, for example through lower greenhouse gas (GHG) emissions, it would be preferable to choose the pricing system with (1) the most RESs and/or (2) the fewest conventional power plants. Based on the results that we derived from our models and using the simplified representation of the Sumatra and Java–Bali electricity systems, this would be the uniform pricing system. Compared with the nodal (zonal) pricing system, under the uniform pricing system, there is around 10,000 MW (8,000 MW) more RES capacity and around 12,000 MW (9,000 MW) less conventional capacity. Comparing nodal with zonal pricing indicates that the zonal pricing system would be the second-best option with respect to energy sustainability.

6.1.2 Energy Security

This horn of the energy trilemma emphasizes that adequate generation capacity is available and that it is possible to transport the generated electricity reliably to the consumers. Our results indicate that all three pricing systems incentivize additional investments that are remunerated via prices: as Section 5 described, each pricing system allows the addition of both renewable and conventional generation capacities. Furthermore, under all three pricing systems, the TSO invests in the necessary network capacity to integrate the private investments in the best possible way into the overall system. As the private investments vary between the three pricing systems, the optimal network investments also depend on the respective market design. In particular, our results illustrate that, under nodal and zonal pricing, the TSO would build only three and five new lines, with an aggregated capacity of 3,000 MW and 4,400 MW, respectively, while, under uniform pricing, it would construct 13 new lines, with an aggregated capacity of 12,544 MW. Ultimately, all three systems contribute to energy security in the sense that they add new capacities to the system. However, what distinguishes the zonal and uniform pricing systems from the nodal pricing system with respect to energy security is that redispatch is necessary under the latter two systems. Here, it is important to implement redispatch appropriately, as blackouts or brownouts may otherwise occur.

6.1.3 Energy Equity

This horn of the energy trilemma emphasizes the affordability of energy services, mainly from the perspective of consumers. Two indicators from our results allow us to draw conclusions regarding which pricing system seems to have advantages for this horn of the trilemma. First, comparing the electricity prices resulting under each pricing system reveals that the lowest average electricity price occurs under the nodal pricing system (i.e., 29.06 $/MWh), with the zonal (i.e., 31.33 $/MWh) and the uniform pricing system (i.e., 32.45 $/MWh) in the second and third places, respectively. For a detailed discussion, please see Section 6.2. Second, the consumer surplus—indicating the realized monetary benefits for consumers—is higher under the nodal pricing system than under the zonal pricing system. The uniform pricing system is the one that yields the lowest consumer surplus.

To summarize, our results, which we presented in Section 5, indicate that, for the simplified representation of the Sumatra and Java–Bali energy system, there may be evidence that a nodal pricing system can support Indonesia in achieving energy equity (see Section 6.2); a uniform pricing system may support Indonesia in achieving energy sustainability under the given input parameters; and all three pricing systems may support Indonesia in achieving energy security but vary in the exact investment amounts. Nodal pricing produces the overall welfare optimum. However, we noted that the overall results for the model of the zonal pricing system are very similar to the results that we obtained under the nodal pricing system: in particular, welfare decreases only by 0.66 percentage points under the zonal pricing system compared with the nodal pricing system. As we discussed in Section 2.1, a nodal pricing system may yield greater complexity than a zonal pricing system. Accordingly, when deciding which pricing system to implement, policymakers' decisions may also reflect this circumstance. Hence, for our simplified representation, zonal pricing might actually have advantages over nodal pricing. Finally, the above results underline our discussion of the three pricing systems in Section 2.1: considering the three horns of the energy trilemma that policymakers focus on, no "best" pricing system exists; rather, the three pricing systems have quite different impacts. When considering the three pricing systems, policymakers may therefore reflect on which horn(s) of the energy trilemma their country needs to focus on in the future. Furthermore, policymakers may take the concept of energy justice into account, and the following section discusses this further.

6.2 An Energy Justice Perspective on Indonesia's Energy Trilemma

As a consequence of the challenges that the previous section discussed, literature has highlighted the possibility of resolving the problem of balancing the energy trilemma through energy justice; see, for example, Heffron, McCauley, and Sovacool (2015) or Heffron, McCauley, and Rubens (2018). In particular, Maulidia et al. (2019) recently proposed this approach for Indonesia. In brief, energy justice is about the application of human rights across the energy life cycle; in particular, there are five forms of justice at its core: distributive, procedural, recognition, restorative, and cosmopolitan justice (Heffron and McCauley 2017). Given these five forms of energy justice, applying a distribution justice perspective to our results in particular promises valuable additional insights. Subsequently, we therefore focused our analysis on the distributional effects of the three pricing systems. However, we will also briefly address the remaining four forms of energy justice below and describe how they may relate to our results in the context of introducing a wholesale market for electricity in Indonesia.

Distributive justice emphasizes the distribution of benefits and drawbacks resulting from the energy sector (Heffron and McCauley 2017). Against this background and based on our results in Section 5, we highlight the distributional effects for consumers as a result of the electricity prices that they have to pay under each pricing system. First, if policymakers in Indonesia were to decide to introduce a nodal price system, they would have to consider that the resulting electricity prices may vary significantly for consumers at different nodes; see also Table 3 for an overview of the average electricity prices that consumers would have to pay at each node under the three pricing systems. For instance, as Table 3 illustrates, under the nodal pricing system, consumers located at nodes 1–7 and 9 on Sumatra would have to pay 25.83 \$/MWh on average, while consumers located at node 8 would have to pay 29.24 \$/MWh. This means that consumers at node 8 would have to pay a price for electricity that is 13.2% higher than the price that consumers at node 6 have to pay on average. Although such price spreads reflect the inherent logic of a nodal pricing system and lead to overall economic efficiency, it might be difficult for policymakers to explain the necessity of such price spreads to consumers. As a consequence, consumers might perceive the differences in electricity prices to be unfair and acceptance problems may arise.

Second, while the discussion in Section 6.1 demonstrated that a zonal pricing system yields the lowest average electricity price, and this may be favorable in terms of energy equity, distributive justice focuses the perspective on the different prices for consumers in “Sumatra” and “Java–Bali.” In fact, consumers in “Sumatra” on average only pay 26.21 \$/MWh, while consumers in “Java–Bali” pay 32.72 \$/MWh. This means that consumers in “Java–Bali” pay 24.8% more than consumers in “Sumatra.” For consumers in “Java–Bali,” therefore, a uniform pricing system would actually be more attractive than the zonal pricing system, as they would pay a lower price.

Third, with the uniform pricing system, we could reverse the first argument with respect to nodal pricing. All consumers pay the same price (i.e., 32.45 \$/MWh in our case); therefore, at least from the consumers’ point of view, there is no reason to feel that they are being treated unequally. However, the overall economic efficiency of the energy system suffers significantly from the fact that prices incentivize inefficient investments on the generation side.

Table 3: Average Electricity Prices for Consumers in Each Pricing System
(\$/MWh)

	Pricing System		
Node	**Nodal**	**Zonal**	**Uniform**
1	25.83	30.28	32.45
2	25.83	30.28	32.45
3	25.83	30.28	32.45
4	25.83	30.28	32.45
5	25.83	30.28	32.45
6	25.83	30.28	32.45
7	25.83	30.28	32.45
8	29.24	30.28	32.45
9	25.83	30.28	32.45
“Sumatra”	26.21	30.28	32.45
10	32.77	32.69	32.45
11	32.69	32.69	32.45
12	32.69	32.69	32.45
13	32.77	32.69	32.45
14	32.77	32.69	32.45
15	32.69	32.69	32.45
16	32.69	32.69	32.45
“Java–Bali”	32.72	32.69	32.45

Abbreviation: MWh = megawatt-hour.

Source: Authors’ creation.

Furthermore, we reflect that the overall results for nodal and zonal pricing (see Table 2) do not differ significantly. Hence, when reflecting only the zonal and uniform pricing systems, the electricity prices in Table 3 indicate that the difference between the zonal and the uniform electricity prices for “Java–Bali” is rather small. Consequently, regarding distributive justice, policymakers may consider whether to implement zonal pricing—from which consumers in “Sumatra” benefit significantly—or uniform pricing—which would entail higher RES investments for the whole system.

To conclude, the previous examples illustrate that introducing a new electricity pricing system may have significant distributional implications. Clearly, some consumers benefit from a certain pricing system (i.e., they pay relatively low prices for electricity) while others may suffer (i.e., they pay relatively high prices for electricity). Past experience in various countries illustrates that reforms of pricing mechanisms (e.g., introducing a nodal, zonal, or uniform pricing system) can have various adverse effects, including inflicting hardship on the poor and vulnerable (Rentschler and Bazilian 2017). In Indonesia, past subsidy reform attempts and the resulting increases in fuel prices have triggered widespread protests and rioting (Gunningham 2013). It is therefore necessary for policymakers to consider carefully the distributional impacts of introducing one of the three pricing systems. In particular, additional measures, such as compensating vulnerable households, may accompany the implementation process (Rentschler and Bazilian 2017).

As we noted above, the concept of energy justice comprises four more forms of justice that may guide Indonesian policymakers when considering a major reform such as liberalization of the electricity sector. While further information is available from Heffron and McCauley (2017), in the following, we will briefly address the four forms of justice in the light of our case study. First, procedural justice emphasizes compliance with the law while preparing and implementing reforms. It includes ensuring that the needs and concerns of all stakeholders (e.g., citizens, firms, or PLN in Indonesia) are heard equally (Heffron and McCauley 2017). For example, it is important to prevent an interest group from being able to influence political decisions to its own advantage, which has been a major challenge for Indonesia in the past. In 2017, the domestic coal industry's lobbying made the Indonesian Government reverse its plans to put a cap on coal production (Clark, Zucker, and Urpelainen 2020). In line with procedural justice, it is necessary to prevent such unilateral influence.

Second, recognition justice emphasizes the recognition of rights for different groups in Indonesia (Heffron and McCauley 2017). In particular, all individuals must have fair representation and complete and equal political rights (Heffron, McCauley, and Sovacool 2015). For instance, this may entail Indonesian policymakers considering poor and vulnerable households in particular when choosing a certain pricing system.

Third, restorative justice emphasizes the rectification of any injustices that the energy sector causes (Heffron and McCauley 2017). Such a major reform of the energy system as we examine in this paper offers policymakers in Indonesia the opportunity to correct historically grown injustices in the energy system.

Finally, cosmopolitan justice emphasizes that the people of Indonesia consider themselves as citizens of the world and considers the effects of its energy policy beyond Indonesia and in a global context (Heffron and McCauley 2017). This means that the reforms of the Indonesian energy system are important not only for Indonesia itself but also for the rest of the world and vice versa: climate change is a global problem, and, if Indonesia does not succeed in reducing the emission of GHGs from its electricity production, other countries will also suffer from the environmental damage.

To conclude, complementing the discussion of our results with an energy justice perspective on introducing a new electricity pricing system broadens the perspective toward the socially just aspects of an electricity market reform.

6.3 Policy Implications and Transition Pathway

In this section, we summarize the general policy implications that result from the discussion in the previous sections. Additionally, we outline a first transition pathway indicating when and how policymakers in Indonesia can implement the reforms necessary for introducing one of the three pricing systems that this paper discusses.

Existing research has highlighted that electricity markets remain a work in progress in South East Asia (Eberhard and Godinho 2017). As Section 2.2 discussed, policymakers in Indonesia face challenges in providing all citizens with electricity reliably and affordably while also increasing the share of RESs in the energy mix. What they need to cope with these challenges is a clear policy direction (Taghizadeh-Hesary and Yoshino 2019). In our paper, we have suggested and investigated a major reform of the Indonesian energy system, that is, the introduction of a wholesale market for electricity with one of three corresponding electricity pricing systems. From the results that Sections 5, 6.1, and 6.2 discussed, we derive the following implications for Indonesian policymakers.

There is no electricity pricing system that addresses all three horns of the energy trilemma equally. Rather, each pricing system may support Indonesia in achieving a specific horn. Therefore, policymakers must first decide which horn(s) they want to focus on and, based on this decision, then choose the appropriate pricing system. For example, given that Indonesia is lagging behind in terms of reaching its RES targets for 2025 and beyond, the uniform pricing system may be an appropriate option. If, however, the focus of policymakers remains on the affordability of electricity, the nodal pricing system might be preferable. Given our results, a zonal pricing system might be the right choice if policymakers aim to achieve a balance between energy sustainability and energy equity.

Building on the previous sections and the above implications, in the following, we briefly outline a transition pathway through which Indonesia may introduce one of the three pricing systems and thereby ultimately move toward a more just energy transition. We build on Rotmans, Kemp, and van Asselt (2001), who considered four phases of transition: (1) the pre-development phase, (2) the take-off phase, (3) the acceleration phase, and (4) the stabilization phase. In the pre-development phase, a country is in a dynamic equilibrium in which the status quo does not visibly change. As Section 2.2 discussed in detail, Indonesia is indeed in such a pre-development phase with respect to liberalizing its energy system. To progress to the take-off phase (i.e., the process of change commences because the state of the system begins to shift), government and energy policymakers need to start the reform process. In our context, this means that policymakers take the first steps to introduce a wholesale market for electricity and implement one of the three pricing systems that we discussed throughout the paper. Based on our discussion in the previous sections, policymakers should first decide what their actual goal is with respect to achieving the three horns of the energy trilemma. Next, they may choose the corresponding and appropriate electricity pricing system and implement it. Exemplary steps that will be necessary during implementation comprise reducing the level of state control in the energy system, opening the market to independent and private parties, and establishing a power exchange with corresponding permissions. During this take-off phase, in particular, it is important that procedural and recognition justice are present. In the acceleration phase (i.e., visible structural changes take place through an accumulation of socio-cultural, economic, ecological, and institutional changes that reflect each other), it will be important for policymakers to be oriented toward set goals, for example in the form of milestones with exact due dates. An exemplary milestone may relate to the question of when a power exchange starts its operation. Finally, the stabilization phase is the phase in which Indonesia will successfully liberalize its energy system and adequately address the energy trilemma through the newly introduced market mechanisms. During all of these four phases, it is particularly important that those who are responsible for the reform as well as the future market participants acquire know-how on how a liberalized wholesale market for electricity functions and how they can organize it efficiently. Against this background, it will be essential to build actively on the experience that countries around the world have gained in introducing the different pricing systems (see Section 2.1).

7. CONCLUSION

In this paper, we analyzed an electricity market reform concerning the introduction of a wholesale market for electricity with respect to balancing the energy trilemma. We developed three generic models that allow policymakers to analyze the impact of introducing a nodal, a zonal, or a uniform pricing system on the three horns of the energy trilemma in their country. We evaluated our approach using a simplified network representation of the Indonesian electricity system with first real-world data; in particular, we focused on the electricity systems of Sumatra and Java–Bali. The results of our evaluation indicate that none of the pricing systems is able to balance all three horns of the trilemma in Indonesia equally. However, we found that each of the pricing systems is able to foster specific horns of the energy trilemma. Among others, we found that a nodal pricing system maximizes welfare in Indonesia, whereas a uniform pricing system supports energy sustainability (i.e., an increase in RESs). Furthermore, our paper offered relevant implications for both research and practice. Our results indicate the need for a connection of the two islands of Sumatra and Java–Bali as our evaluation shows that, under each of the three pricing systems, it is possible to build corresponding transmission lines. According to our results, policymakers may first consider which horn of the energy trilemma they want to focus on and then implement the appropriate electricity pricing system in the next step. Moreover, we broadened the discussion of our results toward an energy justice perspective on Indonesia's energy trilemma. In particular, we discussed the fact that it is always necessary to consider the choice of a certain electricity pricing system under its distributional effects. For example, we stated that policymakers may consider whether to foster RES investments within the whole system (i.e., the introduction of uniform pricing) or whether to introduce zonal pricing under which consumers in Sumatra benefit while consumers in Java–Bali are not significantly inferior. Based on these implications, we ultimately illustrated a transformation pathway that may guide (Indonesian) policymakers in introducing a wholesale market for electricity including one of the three pricing systems that we discussed in the paper.

Although our approach is in line with the current literature, there are inherent limitations that we want to outline briefly here. First, the results of our evaluation are limited to the electricity networks of Sumatra and Java–Bali, while the general applicability of our developed models holds for any other country or region. Second, due to a lack of real-world data, the data that our evaluation uses contain several assumptions, for example regarding exact network capacities. Third, our models are limited regarding further policy instruments like network fees, which they do not consider. Furthermore, we note that developing Indonesia's current single-buyer model to a wholesale market model may entail practical challenges that we did not consider in our paper, for example Indonesia's political economy.

Future research may focus, for example, on the integration of storage into our model, which may be of relevance with respect to energy security. Moreover, research may extend our model by considering the concept of demand side flexibility and its possible effects on electricity price peaks. Of course, future research may also enhance our data set and extend the evaluation to all the regions of Indonesia. In summary, the models that we developed in this paper provide a manifold foundation for research and practice regarding the analysis of impacts concerning the introduction of a wholesale market for electricity in Indonesia. In particular, our evaluation results and respective discussions may serve as a valuable basis for policymakers regarding the successful implementation of electricity market reforms.

REFERENCES

Asian Development Bank (ADB). 2019. *Renewable Energy Financing Schemes for Indonesia*. Manila, Philippines.

Batih, H., and C. Sorapipatana. 2016. "Characteristics of Urban Households' Electrical Energy Consumption in Indonesia and Its Saving Potentials." *Renewable and Sustainable Energy Reviews* 57: 1160–73. doi:10.1016/j.rser.2015.12.132.

Bjørndal, M., and K. Jørnsten. 2001. "Zonal Pricing in a Deregulated Electricity Market." *The Energy Journal* 22 (1). doi:10.5547/ISSN0195-6574-EJ-Vol22-No1-3.

———. 2007. "Benefits from Coordinating Congestion Management—The Nordic Power Market." *Energy Policy* 35 (3): 1978–91. doi:10.1016/j.enpol.2006.06.014.

Bjørndal, M., K. Jørnsten, and V. Pignon. 2003. "Congestion Management in the Nordic Power Market—Counter Purchases and Zonal Pricing." *Competition and Regulation in Network Industries* 4 (3): 271–92. doi:10.1177/178359170300400302.

Bohn, R. E., M. C. Caramanis, and F. C. Schweppe. 1984. "Optimal Pricing in Electrical Networks over Space and Time." *RAND Journal of Economics* 15 (3): 360. doi:10.2307/2555444.

Boucher, J., and Y. Smeers. 2001. "Alternative Models of Restructured Electricity Systems, Part 1: No Market Power." *Operations Research* 49 (6): 821–38. doi:10.1287/opre.49.6.821.10017.

Burke, P. J., and S. Kurniawati. 2018. "Electricity Subsidy Reform in Indonesia: Demand-Side Effects on Electricity Use." *Energy Policy* 116: 410–21. doi:10.1016/j.enpol.2018.02.018.

Burke, P. J., J. Widnyana, Z. Anjum, E. Aisbett, B. Resosudarmo, and K. G. H. Baldwin. 2019. "Overcoming Barriers to Solar and Wind Energy Adoption in Two Asian Giants: India and Indonesia." *Energy Policy* 132: 1216–28. doi:10.1016/ j.enpol.2019.05.055.

Burstedde, B. 2012. "From Nodal to Zonal Pricing: A Bottom-up Approach to the Second-Best." In *2012 9th International Conference on the European Energy Market*, 1–8. IEEE.

Chang, Y., and Y. Li. 2015. "Renewable Energy and Policy Options in an Integrated ASEAN Electricity Market: Quantitative Assessments and Policy Implications." *Energy Policy* 85: 39–49. doi:10.1016/j.enpol.2015.05.011.

Chao, H.-P., and S. Peck. 1996. "A Market Mechanism for Electric Power Transmission." *Journal of Regulatory Economics* 10 (1): 25–59. doi:10.1007/ BF00133357.

Clark, R., N. Zucker, and J. Urpelainen. 2020. "The Future of Coal-Fired Power Generation in Southeast Asia." *Renewable and Sustainable Energy Reviews* 121: 109650. doi:10.1016/j.rser.2019.109650.

Conejo, A. J., and R. Sioshansi. 2018. "Rethinking Restructured Electricity Market Design: Lessons Learned and Future Needs." *International Journal of Electrical Power & Energy Systems* 98: 520–30. doi:10.1016/j.ijepes.2017.12.014.

Daxhelet, O., and Y. Smeers. 2007. "The EU Regulation on Cross-Border Trade of Electricity: A Two-Stage Equilibrium Model." *European Journal of Operational Research* 181 (3): 1396–1412. doi:10.1016/j.ejor.2005.12.040.

Ding, F., and J. D. Fuller. 2005. “Nodal, Uniform, or Zonal Pricing: Distribution of Economic Surplus.” *IEEE Transactions on Power Systems* 20 (2): 875–82. doi:10.1109/TPWRS.2005.846042.

Direktorat Jenderal Energi Baru Terbarukan Dan Konservasi Energi (Ditjen EBTKE). 2016. *Statistik EBTKE 2016*.

———. 2019. *LKJ Ditjen EBTKE 2018*.

Dutu, R. 2016. “Challenges and Policies in Indonesia's Energy Sector.” *Energy Policy* 98: 513–19. doi:10.1787/5js0cqqk42ls-en.

Eberhard, A., and C. Godinho. 2017. *A Review and Exploration of the Status, Context and Political Economy of Power Sector Reforms in Sub-Saharan Africa, South Asia and Latin America*. UC Berkeley: Center for Effective Global Action. https://escholarship.org/uc/item/11k4210h. Accessed February 7, 2020.

Egerer, J., J. Weibezahn, and H. Hermann. 2016. “Two Price Zones for the German Electricity Market—Market Implications and Distributional Effects.” *Energy Economics* 59: 365–81.

Ehrenmann, A., and Y. Smeers. 2005. “Inefficiencies in European Congestion Management Proposals.” *Utilities Policy* 13 (2): 135–52. doi:10.1016/j.jup.2004.12.007.

Gan, D., and D. V. Bourcier. 2002. “Locational Market Power Screening and Congestion Management: Experience and Suggestions.” *IEEE Transactions on Power Systems* 17 (1): 180–85.

Gil, H. A., and J. Lin. 2013. “Wind Power and Electricity Prices at the PJM Market.” *IEEE Transactions on Power Systems* 28 (4): 3945–53.

Gleixner, A., M. Bastubbe, L. Eifler, T. Gally, G. Gamrath, R. L. Gottwald, G. Hendel et al. 2018. “The SCIP Optimization Suite 6.0.” Technical Report. http://www.optimization-online.org/DB_HTML/2018/07/6692.html.

Global Energy Monitor. 2020. “Global Coal Plant Tracker.” Accessed March 19, 2020. https://endcoal.org/tracker/.

Grimm, V., A. Martin, M. Schmidt, M. Weibelzahl, and G. Zöttl. 2016. “Transmission and Generation Investment in Electricity Markets: The Effects of Market Splitting and Network Fee Regimes.” *European Journal of Operational Research* 254 (2): 493–509. doi:10.1016/j.ejor.2016.03.044.

Gunningham, N. 2013. “Managing the Energy Trilemma: The Case of Indonesia.” *Energy Policy* 54: 184–93. doi:10.1016/j.enpol.2012.11.018.

Handayani, K., Y. Krozer, and T. Filatova. 2017. “Trade-Offs between Electrification and Climate Change Mitigation: An Analysis of the Java–Bali Power System in Indonesia.” *Applied Energy* 208: 1020–37. doi:10.1016/j.apenergy.2017.09.048.

Heffron, R. J., and D. McCauley. 2017. “The Concept of Energy Justice across the Disciplines.” *Energy Policy* 105: 658–67. doi:10.1016/j.enpol.2017.03.018.

Heffron, R. J., D. McCauley, and G. Z. de Rubens. 2018. “Balancing the Energy Trilemma through the Energy Justice Metric.” *Applied Energy* 229: 1191–1201. doi:10.1016/j.apenergy.2018.08.073.

Heffron, R. J., D. McCauley, and B. K. Sovacool. 2015. “Resolving Society's Energy Trilemma through the Energy Justice Metric.” *Energy Policy* 87: 168–76. doi:10.1016/j.enpol.2015.08.033.

Hogan, W. W. 1992. “Contract Networks for Electric Power Transmission.” *Journal of Regulatory Economics* 4 (3): 211–42. doi:10.1007/BF00133621.

———. 2002. “Electricity Market Restructuring: Reforms of Reforms.” *Journal of Regulatory Economics* 21 (1): 103–32.

IBM. 2019. “IBM ILOG CPLEX Optimization Studio.” IBM. Accessed March 20, 2020. https://www.ibm.com/products/ilog-cplex-optimization-studio.

Institute for Essential Services Reform (IESR). 2019a. “A Roadmap for Indonesia's Power Sector: How Renewable Energy Can Power Java-Bali and Sumatra.” Unpublished manuscript, last modified March 4, 2020. http://iesr.or.id/pustaka/technical-report-a-roadmap-for-indonesias-power-sector/.

———. 2019b. “Calculator of Levelized Cost of Electricity for Power Generation Technologies.” Accessed March 19, 2020. http://iesr.or.id/lcoe-tools/.

Kahn, A. E., P. C. Cramton, R. H. Porter, and R. D. Tabors. 2001. “Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond.” *Electricity Journal* 14 (6): 70–79.

Kennedy, S. F. 2018. “Indonesia’s Energy Transition and Its Contradictions: Emerging Geographies of Energy and Finance.” *Energy Research & Social Science* 41: 230–37. doi:10.1016/j.erss.2018.04.023.

Koch, T. 2004. *Rapid Mathematical Prototyping*.

Leuthold, F., H. Weigt, and C. von Hirschhausen. 2008. “Efficient Pricing for European Electricity Networks—The Theory of Nodal Pricing Applied to Feeding-in Wind in Germany.” *Utilities Policy* 16 (4): 284–91.

Liebman, A., A. Reynolds, D. Robertson, S. Nolan, M. Argyriou, and B. Sargent. 2019. “Green Finance in Indonesia.” In *Handbook of Green Finance*, Vol. 98, edited by Jeffrey Sachs, Wing T. Woo, Naoyuki Yoshino, and Farhad Taghizadeh-Hesary, 1st ed., 1–30. Singapore: Springer Singapore.

Lovei, L. 2000. *The Single-Buyer Model: A Dangerous Path Toward Competitive Electricity Markets*.

Maulidia, M., P. Dargusch, P. Ashworth, and F. Ardiansyah. 2019. “Rethinking Renewable Energy Targets and Electricity Sector Reform in Indonesia: A Private Sector Perspective.” *Renewable and Sustainable Energy Reviews* 101: 231–47. doi:10.1016/j.rser.2018.11.005.

Ministry of Energy and Mineral Resources (MEMR). 2013. Peraturan Menteri ESDM No. 17 Tahun 2013 Tentang Pembelian Tenaga Listrik Oleh PT Perusahaan Listrik Negara (Persero) Dari Pembangkit Listrik Tenaga Surya Fotovoltaik. MEMR. 2013. Accessed March 28, 2020. https://jdih.esdm.go.id/index.php/web/result/803/detail.

———. 2016. Peraturan Menteri ESDM No. 19 Tahun 2016 Tentang Pembelian Tenaga Listrik Dari Pembangkit Listrik Tenaga Surya Fotovoltaik Oleh PT Perusahaan Listrik Negara (Persero). MEMR. 2016. Accessed March 28, 2020. https://jdih.esdm.go.id/index.php/web/result/1535/detail.

———. 2017a. Peraturan Menteri Energi Dan Sumber Daya Mineral Nomor 50 Tahun 2017 Tentang Pemanfaatan Sumber Energi Terbarukan Untuk Penyediaan Tenaga Listrik. MEMR. 2017a. Accessed March 28, 2020. https://jdih.esdm.go.id/index.php/web/result/1698/detail.

———. 2017b. Peraturan Menteri ESDM No. 12 Tahun 2017 Tentang Pemanfaatan Sumber Energi Terbarukan Untuk Penyediaan Tenaga Listrik. MEMR. 2017b. Accessed March 28, 2020. https://jdih.esdm.go.id/index.php/web/result/1621/detail.

———. 2019. *Rencana Umum Ketenagalistrikan Nasional 2019–2038*.

Müsgens, F., A. Ockenfels, and M. Peek. 2014. "Economics and Design of Balancing Power Markets in Germany." *International Journal of Electrical Power & Energy Systems* 55: 392–401.

Oggioni, G., and Y. Smeers. 2013. "Market Failures of Market Coupling and Counter-Trading in Europe: An Illustrative Model Based Discussion." *Energy Economics* 35: 74–87. doi:10.1016/j.eneco.2011.11.018.

Pechan, A. 2017. "Where Do All the Windmills Go? Influence of the Institutional Setting on the Spatial Distribution of Renewable Energy Installation." *Energy Economics* 65: 75–86. doi:10.1016/j.eneco.2017.04.034.

Pollitt, M. G. 2012. "The Role of Policy in Energy Transitions: Lessons from the Energy Liberalisation Era." *Energy Policy* 50: 128–37. doi:10.1016/j.enpol.2012.03.004.

PT Perusahaan Listrik Negara (PT PLN). 2018. *Rencana Usaha Penyediaan Tenaga Listrik PT PLN (Persero) 2018–2027*.

———. 2019a. *PLN Statistics 2018*.

———. 2019b. *Rencana Usaha Penyediaan Tenaga Listrik PT PLN (Persero) 2019–2028*.

Rentschler, J., and M. Bazilian. 2017. "Reforming Fossil Fuel Subsidies: Drivers, Barriers and the State of Progress." *Climate Policy* 17 (7): 891–914. doi:10.1080/14693062.2016.1169393.

Rotmans, J., R. Kemp, and M. van Asselt. 2001. "More Evolution Than Revolution: Transition Management in Public Policy." *Foresight—The Journal of Future Studies, Strategic Thinking and Policy* 3 (1): 15–31.

Sakya, I. M. R., U. R. Simanjutak, P. H. Schavemaker, and L. van Sluts der. 2006. "Experience with Internal Competition Using the Single Buyer Model in Jawa Bali— Indonesia." In *2006 Eleventh International Middle East Power Systems Conference*.

Schweppe, Fred C., Michael C. Caramanis, Richard D. Tabors, and Roger E. Bohn. 1988. *Spot Pricing of Electricity*. The Kluwer International Series in Engineering and Computer Science, Power Electronics & Power Systems. Boston, MA: Springer.

Singh, H., S. Hao, and A. Papalexopoulos. 1998. "Transmission Congestion Management in Competitive Electricity Markets." *IEEE Transactions on Power Systems* 13 (2): 672–80. doi:10.1109/59.667399.

Tabrizian, S. 2019. "Technological Innovation to Achieve Sustainable Development—Renewable Energy Technologies Diffusion in Developing Countries." *Sustainable Development* 27 (3): 537–44. doi:10.1002/sd.1918.

Taghizadeh-Hesary, F., and N. Yoshino. 2019. "The Way to Induce Private Participation in Green Finance and Investment." *Finance Research Letters* 31: 98–103. doi:10.1016/j.frl.2019.04.016.

Vogelsang, I. 2006. "Electricity Transmission Pricing and Performance-Based Regulation." *The Energy Journal* 27 (4): 97–126.

Weibelzahl, M. 2017. "Nodal, Zonal, or Uniform Electricity Pricing: How to Deal with Network Congestion." *Frontiers in Energy* 11 (2): 210–32. doi:10.1007/s11708-017-0460-z.

Weibelzahl, M., and A. Märtz. 2020. "Optimal Storage and Transmission Investments in a Bilevel Electricity Market Model." *Annals of Operations Research* 287 (2): 911–40. doi:10.1007/s10479-018-2815-1.

World Bank. 2019a. "Gross Domestic Product 2018." Unpublished manuscript, last modified February 7, 2020. https://datacatalog.worldbank.org/dataset/gdp-ranking.

———. 2019b. "Population 2018." Unpublished manuscript, last modified February 27, 2020. https://databank.worldbank.org/data/download/POP.pdf.

———. 2020a. "Access to Electricity (% of Population)—Indonesia." Unpublished manuscript, last modified February 7, 2020. https://data.worldbank.org/indicator/EG.ELC.ACCS.ZS?locations=ID&name_desc=false.

———. 2020b. "Poverty Headcount Ratio at $1.90 a Day (2011 PPP) (% of Population)." Unpublished manuscript, last modified February 8, 2020. https://data.worldbank.org/topic/poverty?locations=ID.

———. 2020c. "World Bank Country and Lending Groups." https://datahelpdesk.worldbank.org/knowledgebase/articles/906519-world-bank-country-and-lending-group.

APPENDIX 1: SETS, PARAMETERS, AND VARIABLES

This appendix presents a summary of the main sets, parameters, and variables that we used in our models.

Table 4: Sets

Symbol	Description
$\mathcal{G}$	Electricity network
N	Set of network nodes
$C \subseteq N$	Set of consumer nodes
L	Set of transmission lines
$L^{\text{ex}} \subseteq L$	Set of existing transmission lines
$L^{\text{new}} \subseteq L$	Set of candidate transmission lines
T	Set of time periods
Z	Set of given price zones
G	Set of conventional generators
$G_n \subseteq G$	Set of conventional generators located at node $\boldsymbol{n}$
$G^{\text{ex}} \subseteq G$	Set of existing conventional generators
$G^{\text{new}} \subseteq G$	Set of new conventional generators
R	Set of renewable generators
$R_n \subseteq R$	Set of renewable generators located at node $\boldsymbol{n}$
$R^{\text{ex}} \subseteq R$	Set of existing renewable generators
$R^{\text{new}} \subseteq R$	Set of new renewable generators

Source: Authors' creation.

Table 5: Parameters

Symbol	Description	Unit
a_{ct}	Intercept of demand function c in period t	\$/MWh
b_c	Slope of demand function c	\$/MWh^2
v_g	Variable production cost of generator g	\$/MWh
v_r	Variable production cost of generator r	\$/MWh
$\bar{x}_r$	Maximum power output of generator r	MW
$\bar{y}_g$	Maximum power output of generator g	MW
$\bar{f}_l$	Transmission capacity of line l	MWh
B_l	Susceptance of line l	MWh
i_l	Line investment cost for $l \in L^{new}$	\$
k	Number of price zones	1
i_g	Generation investment cost for g	\$/MWh
i_r	Generation investment cost for r	\$/MWh

Abbreviations: MWh = megawatt-hour, MWh^2 = megawatt-hour squared, MW = megawatt.
Source: Authors' creation.

Table 6: Variables and Derived Quantities

Symbol	Description	Unit
d_{ct}	Electricity demand at node c in period t	MWh
x_{rt}	Electricity generation of generator r in period t	MWh
y_{gt}	Electricity generation of generator g in period t	MWh
$\bar{x}_r$	Invested generation capacity of generator r	MW
$\bar{y}_g$	Invested generation capacity of generator g	MW
f_{lt}	Power flow on line l in period t	MWh
Θ_{nt}	Phase angle value at node n in period t	rad
w_l	Line extension variable for candidate line $l \in L^{new}$	{0, 1}

Abbreviations: MWh = megawatt-hour, MW = megawatt, rad = radiant.

Source: Authors' creation.

APPENDIX 2: DATA DESCRIPTION

In this appendix, we present more detailed information on the model inputs that we used.

Table 7: Overview of Nodes (Provinces of Sumatra and Java–Bali) of the Considered Network

Name	ID
Sumatra	
Aceh	1
North Sumatra	2
Riau (incl. Riau Islands)	3
West Sumatra	4
Jambi	5
Bengkulu	6
South Sumatra	7
Bangka Belitung	8
Lampung	9
Java	
Jakarta	10
Banten	11
West Java	12
Central Java	13
Yogyakarta	14
East Java	15
Lesser Sunda Islands	
Bali	16

Abbreviation: ID = identification number.

Source: Authors' creation.

Table 8: Overview of the Existing Generation Capacities
(MW)

ID	Coal	Gas	Diesel	Hydro	Geothermal	Wind	Solar PV	Biomass	Total
1	220	380	96.2	–	–	–	–	–	696.2
2	800	1,286.4	270.6	520.9	350	–	–	–	3,227.9
3	249	432.2	420.58	114	–	–	–	0.9	1,216.68
4	406.5	–	63.09	286.5	–	–	–	–	756.09
5	12	359.2	10.4	–	–	–	–	–	381.6
6	–	–	41.7	236.3	–	–	–	–	278
7	1,277	863.9	25	23.7	–	–	–	–	2,189.6
8	93	75	126.5	–	–	–	–	11	305.5
9	454	160	0.4	174.3	210				998.7
10	–	3,539	–	–	–	–	–	–	3,539
11	6,201.3	740	–	–	–	–	–	–	6,941.3
12	2,700	2,452	–	1,985.5	1,198.7	–	–	–	8,336.2
13	5,390	–	1,396.4	305.7	60	–	–	–	7,152.1
14	–	–	–	–	–	–	–	–	–
15	6,070	3,004.6	124.88	274.9	–	–	–	–	9,474.38
16	426	–	–	–	–	0.75	0.03	–	426.78
Total	**24,298.8**	**13,292.3**	**2,575.75**	**3,685.3**	**1,818.7**	**0.75**	**0.03**	**11.9**	

Abbreviations: MW = megawatt, ID = identification number, PV = photovoltaics.

Source: Authors' creation based on PT PLN (2018).

Table 9: Techno-Economic Parameters of Generation Technologies

Technology	Lifetime (Years)	Efficiency (%)	Investment Cost ($/kW)	Variable Cost ($/MWh)[a]
Coal, existing	30	34	–	26.8
Coal, new	30	42	1,525	22.1
Gas, existing	25	34	–	69.7
Gas, new	25	56	825	45.3
Diesel	25	46	800	325.5
Large hydro	25	–	1,953[b]	0.55
Small hydro	25	–	3,100	0.55
Geothermal	30	–	4,550	0.25
Wind	25	–	1,750	–
Solar PV	25	–	950	–
Biomass	25	–	1,750	3

[a] Variable cost includes variable operation cost and fuel cost.

[b] In line with similar assumptions (e.g., in Handayani, Krozer, and Filatova 2017), investment costs for large hydro are estimated at 63% of those of small hydro.

Abbreviations: kW = kilowatt, MWh = megawatt-hour.

Source: Authors' creation based on IESR (2019b).